The challenges of crude blending

Declining crude prices encourage more spot purchases that save costs, but mixing different grades can create headaches for refiners

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Lingering low prices since the market rout began in mid-2014 have motivated many refiners around the world to buy more price-advantaged heavy and lighter grades on the spot market and try to blend them together in order to create so-called lookalike crudes similar to what they have been processing. Despite economic incentives, these crudes often exhibit 'dumbbell' properties — a higher proportion of light ends like gasoline and lower-value heavy products like fuel oil and asphalt with a lesser fraction of valuable middle distillates, as well as other undesirable qualities for current refinery configurations. For many refiners, the concerns go beyond crude-refinery mismatch to make products in demand. Equipment failures, unit shutdowns, and even safety problems have been reported, resulting in lost profit opportunities. Anticipating and preventing this mismatch as well as solving the potential problems of the crude cocktails involve a thorough understanding of the crude properties that contribute to these setbacks. Our discussion of crude selection and blending criteria appears in two parts. This first article covers the criteria that are relatively straightforward to characterise: API gravity, paraffin content, total acid number, and contaminants.

The recent trend of increased blending of a variety of crudes appears to have staying power, at least for the foreseeable future, as many watchers anticipate a 'long U-shape' recovery. According to Nobuo Tanaka, former executive director of the International Energy Agency (IEA) in October 2015, oil prices will not return to the $100/bbl range until US shale production starts to dry up around 2020-2025. In the long term, he explained, crude demand from Asia and Africa could be expected to push prices back up, but not on US shale drillers' watch. Shale production is a built-in stabiliser, he said, and will gradually slow down after 2020 or 2025, so again there is a chance of higher prices coming after that. His view is shared by others including analyst Jeff Currie, head of commodities research with Goldman Sachs, who has reiterated that crude prices could still fall as low as $20/bbl, although he rates the likelihood of that at 'below 50%' and said that prices will likely stay below $50/bbl for the duration of 2016. These predictions do get support from the overall market fundamentals as demand growth is rather lacklustre because of the still weakened economies of China, Europe, Japan, and most emerging markets. Furthermore, the long-anticipated interest rate hike by the US Federal Reserve Bank has driven US dollar-denominated crude prices down.

Hard to pass up a bargain

Since mid-2014, global crude prices have been halved. With the spread between Brent and WTI crude narrowing as crude prices have fallen, there has been less economic incentive for refiners on both the US East and West Coasts to bring in railed volumes of Bakken crude from the mid-continent. Freight rates to rail Bakken crude have made the tight oil more expensive relative to overseas barrels imported via tankers. According to energy market data and intelligence firm Genscape, East Coast refiners were expected to import 10.0 million bbl of West African crude in October 2015, up from 6.0 million bbl in September and 9.6 million bbl in August. Over the first seven months of 2015, East Coast refiners imported 3.0-8.0 million bbl of West African crude per month. According to data from Platts, 13 crude tankers carrying 1.83 million bbl had arrived or were due to arrive from West Africa on the US Gulf Coast in October, up from just four vessels (556 000 bbl) in September.

With global markets brimming with crude oil that is both cheap and plentiful, refiners — especially in Asia — are making a higher priority of getting the best profit margins they can obtain, and worrying less about security of supply. For many refiners, that means purchasing less crude under long-term contracts and more on the spot market, a switch that allows them more flexibility when it comes to making the most of bargains that come up. For instance, South Korean refiner SK Innovation said it will buy up to about 6 million bbl of UK Forties crude on a spot basis in 2015. Likewise, JX Nippon Oil & Energy said that the Japanese firm might double its spot buying from about 15% to 30% of all crude purchases. Meanwhile, Indian refiners were on a 'perceptible shift' toward spot markets, estimating that while spot purchases once made up only about 10% of purchases by the country's crude processors, that figure might rise to about 25%.

Variety of crudes and configuration mismatch

Much has been made of a so-called 'mismatch' between US production of light sweet crude oil and refiners that are geared toward processing large volumes of heavy oil that must be imported. Many US refiners along the Gulf Coast have had to make modifications to their plants in order to better take advantage of domestic crude's low price. The mismatch has caused hardship for Latin American oil companies who really have to struggle as the heavy crude they produce requires much more expensive, sophisticated technology to refine. So refiners in Colombia, Ecuador and Mexico are looking to import various types of light crudes, and sell overseas the heavy material that they have struggled to process at their own relatively simple refineries.

Colombia's state-owned Ecopetrol purchased September-loading crude for its Cartagena refinery in 2015, its first imports of crude, probably Nigerian Bonny Light and Russian Varenday, since at least January 2013. While some sources suggested that Ecopetrol might be following the example of Venezuela's PdVSA — which uses imported light crude to dilute heavy grades for export — others said that the imports were more likely to stay in Colombia. A month later, Ecuador's state-run energy firm Petroecuador said that it was looking for a supplier to sign a tender to provide 82 000 b/d of medium sweet crude (most likely Angolan or Nigerian crude) to the South American nation over a year. Meanwhile, Mexico's Pemex is continuing to work toward importing light US crude under a swap arrangement that sources say has already been approved by the US government. Pemex has said that it plans to process the crude at its own refineries, freeing up more of its heavy oil for export.

According to Dario Scaffardi, general manager of Italian refiner Saras, refiners in Europe need to step up their trading game in order to remain competitive, and the traders and plant engineers need to be on the same page. He explained that refinery traders must not simply seek the cheapest crude available. They must also be thoroughly acquainted with their plant's processing capabilities and the product mix that it can be expected to make from each prospective feedstock. Saras itself, he said, has been working hard to match the right crude with both its refinery configuration and the market conditions of the moment, processing 30-35 different grades in 2015, double the number of crudes the plant handled in 2014.

Heightened blending activities worldwide

Low crude prices and refiners' drive to take advantage of inexpensive cargoes have made blending a bonanza. In the US, Jefferson Energy Companies has announced plans to open a heated 100 000 bbl tank at its crude-by-rail terminal in Beaumont, Texas, to blend undiluted heavy Canadian crude with super-light condensate or tight oil to the individual specification of a refinery in order to help that refinery maximise yields or maximise a specific product such as diesel or gasoline. The company's stated aim is to ensure delivery of compatible and consistent crude oil to the refinery, for further blending or direct processing. In Louisiana, Hazelwood has considered plans to construct a $400 million blending terminal that will combine surface storage with underground salt cavern storage and an in-line blending system to allow simultaneous blending of up to 10 different types of crude to provide a 'boutique' crude blend for a given customer based on current market conditions and refinery constraints. Construction is set to begin early 2016, with completion scheduled for early 2018.

South Africa will bring online in 2017 the world's first crude oil blending terminal, allowing heavy crude grades from Latin America to be mixed with lighter grades from West Africa to create so-called 'dumbbell blends' that will be exported to Asia for upgrading to produce cleaner fuels at lower costs. The 13.2 million bbl terminal will cost $161 million and will consist of 12 1.1 million bbl tanks that employ a patented technology to blend the different crude grades, with specialised equipment installed in the tanks using the velocity of the incoming fluid to mix with the crude in the tank. Construction of the terminal, which will be located at South Africa's deepest natural port at Saldanha Bay, was set to commence in 2015. The site's model is based on blending of different grades of crude to supply a specific recipe to a refinery.

Impacts on downstream processes and plant profitability

The choice of crudes greatly affects a refinery's profitability because crude purchases cover as much as 80% of a refinery's operating expenses. Therefore, sourcing inexpensive crudes is the paramount refining strategy in achieving margins and sustaining business. However, it is vital for refiners to consider also any characteristics that might make a particular oil more difficult to process, significantly change the product slate, or increase refinery emissions, particularly greenhouse gas emissions. If precautions are not taken, the impacts of these other factors may well outweigh the discount in purchase price.

Since refineries typically blend multiple crudes together before processing, the capabilities and limitations of the blending system as well as the quality targets of the final crude blend must be considered when purchasing crude. Factors that refiners must take into account are:

• How much of a specific crude can be blended into the refinery slate while still remaining within given criteria for sulphur content, contaminants, API gravity, and so on
• How compatible the crude to be purchased is with the other crude types being used in the refinery
• How much room is available to store the crude and allow it to be blended into the refinery slate in quantities that allow the final blend to still meet the specified criteria.

Once the desired crudes are selected, their blending plays an important role in the economics of the refinery. Optimised crude blending can help minimise incompatibility problems, stabilise process operations, and improve product quality.

Table 1 shows the primary criteria that need to be considered when selecting crudes to integrate into the refinery's crude slate. In order to process successfully any potential additional crude, a refiner must devise a plan to deal with each of the criteria that are applicable to that crude in order to prevent negative impacts on process operations or product specifications. Additionally, refiners must consider the impact that various contaminants and crude properties may have on refinery CO_2 emissions. For example, crudes with high sulphur levels will require extra processing and, therefore, increase CO_2 emissions due to the increased energy requirements. To manage all of these considerations, refiners may turn to process simulation systems.

In crude selection and blending, secondary criteria, such as sediment content, pour point, and viscosity, are indirectly related to the primary criteria and should also be considered. Sediment content may cause sludge to form and therefore increase fouling. Pour point may indicate potential storage and handling problems. Viscosity level must be low enough to allow for pumping.

API gravity

This property is an indicator of the potential for problems from the other properties as noted in **Table 1**. Crudes with low API gravity tend to be of lesser quality and, therefore, present a greater risk for problems than those with high gravity. Heavier crudes also require more extensive processing to obtain the desirable yields and qualities of liquid refined products. Many processing and product problems are due to higher levels of asphaltenes and various contaminants.

Refineries configured for bottom-of-the-barrel upgrading can not operate with light feeds alone. Blending light oils with heavy, asphaltic crudes can provide a mix of products from the CDU that fits refineries' operational needs. However, these so-called dumbbell blends produce relatively large amounts of naphtha and gas oil but low levels of middle distillates. In addition, they

Primary criteria to consider in crude selection and blending

Criterion	Importance
API gravity	Indicator of product yield profile and potential processing problems
Paraffin content	Can produce sludge and wax deposits in storage tanks and transfer lines, and cause fouling in heat exchangers
Total acid number	Might cause corrosion problems, foaming in the desalter, and product quality problems
Contaminants	Often difficult to remove, and may lead to off-spec products, corrosion, catalyst deactivation, and fouling
Asphaltene content	May increase fouling and reduce light product yield
Compatibility	Incompatibility may lead to extensive fouling
Desirable cuts	Produce sizeable volumes of light and middle distillates
Carbon footprint	Crude quality on refinery emissions

Table 1

TAN values for distillation fractions of various crudes, mg KOH/G

Crude	Whole crude TAN	Medium naphtha, 80-150°C	Heavy naphtha, 150-200°C	Kerosene, 200-260°C	AGO, 260-340°C	LVGO, 340-450°C	HVGO, 450-570°C
Alba	1.42	0.0	0.0	0.1	0.8	1.9	2.2
Brent	0.05	N.A.	0.0	0.0	0.0	0.0	0.1
Captain	2.4	N.A.	0.1	0.4	1.3	2.4	2.9
Duri	1.27	0.0	0.1	0.8	2.5	2.7	1.8
Eocene	0.2	0.1	0.1	0.2	0.2	0.2	0.3
Forties	0.1	N.A.	0.0	0.0	0.1	0.3	0.2
Hamaca	0.7	0.0	0.10	0.1	0.3	1.10	1.20
Hibernia	0.11	0.0	0.0	0.0	0.0	0.1	0.2
Minas	0.08	0.1	0.1	0.1	0.1	0.1	0.0

Table 2

may raise issues for a refinery's operations. Increased light ends in the crude feed can lead to premature vaporisation upstream of the desalter and the crude unit heaters. This can be prevented by the addition of an atmospheric preflash, but there is need for caution. While this can reduce pressure drop, prevent premature vaporisation and fouling by asphaltenes in the crude unit heat exchangers, it can also decrease overall unit yields.

Finally, API gravity has a direct effect on ease of water-oil separation, which becomes more difficult as the density of the crude approaches that of water. Therefore, blends of heavy and light crudes may be used to ensure satisfactory separation.

Paraffin content

Paraffinic crudes are common in many parts of the world, though rising supply of North American light tight or shale oils with significant levels of paraffinic hydrocarbons has posed problems for refiners in the region. The paraffinic materials can foul furnaces by undergoing cracking to form polynuclear aromatics and coke. Coke inhibitors may be used to mitigate this problem. Paraffins also can form sludge, solids, and waxes in crude storage tanks and lines. Refineries processing high-wax tight oil can find as much as 5.0 ft (1.5 m) of sludge build-up in a storage tank. Furthermore, lines utilised to transfer the crude out of tankage to the CDU for upgrading may also experience solids and wax accumulation that can lead to line blockage and reduce throughput, thereby negatively impacting overall refinery operation and profitability. The wax in shale crude has an appearance temperature of 93°C (199°F), and it can cause fouling in the crude preheat train and other heat exchangers. These problems may be mitigated by the use of dispersants. Blending of paraffinic and asphaltenic crudes can result in asphaltene instability and sludge formation, but it also promotes stable emulsion in the desalter and fouling in processing equipment.

Total acid number

Total acid number (TAN) is the milligrams of potassium hydroxide (KOH) needed to neutralise the acidity in one gram of oil. High TAN crude — also called high acid crude (HAC) — is priced at a discount to conventional crude oils due to the potential processing and product quality issues resulting from high acidity. What minimum TAN value classifies a crude oil as a HAC is subject to discussion because not all crudes with the same TAN number cause the same extent of processing problems. Chevron, for example, considers any crude with TAN of 1.0 or more to be high acid crude. However, one can find crudes with TAN below this level that have significant acidity in their higher boiling fractions. Examples are shown in **Table 2**.

Depending on the nature of the acids and the sulphur compounds present, crudes with TAN values of less than 0.5 have presented corrosion problems. In general, however, refiners prefer to process crudes with TAN <0.5 and hydrocarbon streams with TAN <1.5.

HACs may negatively affect product quality. Straight run streams of diesel, kerosene, and jet fuel may have total acid numbers above those permitted for final products.

Although TAN accounts for all acidic components in the crude, research has shown that only certain components — namely naphthenic acids — may be responsible for most of the processing issues. Naphthenic acids typically have 10-50 carbons, up to six fused saturated rings, and a carboxyl group.

Desalting is more challenging for HACs than for other crudes, and many older desalter systems have had to be replaced by newer technology in order to handle HAC feeds.

Naphthenic acid corrosion (NAC) appears as isolated, deep pits in areas that are subject to impingement and high-velocity flows. These characteristics differentiate it from sulphidic corrosion. NAC can also occur with highly alloyed materials, such as 12 Cr, AISI 316, and SS 317. **Table 3** lists areas that are susceptible to naphthenic acid corrosion.

Naphthenic acid corrosion: location and influencing factors

Location of corrosion	Important factors affecting corrosion rate
Furnace tubes	• Velocity: increased velocity increases corrosion • Temperature: higher temperatures increase corrosion • Degree of vaporisation: most severe corrosion occurs just below boiling point of the NA • Turbulence: increased turbulence may decrease sulphide film layer and increase corrosion
Transfer lines	• Velocity: increased velocity increases corrosion • Temperature: higher temperatures increase corrosion • Degree of vaporisation: most severe corrosion occurs just below boiling point of the NA • Turbulence: increased turbulence may decrease sulphide film layer and increase corrosion
Vacuum column internals	• Boiling point of NAs: NA corrosion occurs when the acids condense • NA concentration: higher NA concentrations increase corrosion
Side cuts	• NA concentration: higher NA concentrations increase corrosion • Sulphur concentration and type: sulphur may reduce corrosion

Table 3

Common crude contaminants

Contaminant	Impact
Arsenic	Deactivates catalysts by destroying structure; waste disposal issues
Calcium	May cause corrosion problems; may reduce coke value
Copper	May poison FCC catalysts
Filterable solids	Causes fouling and foaming issues; decreases desalting efficiency
Iron	Plugs catalyst pores; causes fouling in CDU; may reduce coke value
Mercury	Poisons catalysts; safety concern; waste disposal issues
Nickel	Causes moderate catalyst deactivation; promotes dehydrogenation reactions
Nitrogen	May lead to catalyst deactivation and off-spec products
Organic chlorides	Fouling and corrosion in crude tower; corrosion in naphtha hydrotreater
Selenium	Safety concern
Sodium	May cause corrosion problems; may lead to catalyst deactivation
Sulphur	Requires extra processing to meet product S specs; safety concern (H_2S); may cause corrosion problems
Vanadium	May lead to catalyst deactivation; toxic when combusted

Table 4

Contaminants

A number of contaminants, both metals and non-metals, must be considered when selecting crude oils for ideal blends. It is important to understand the potential operating problems in order to assess whether the trade-off between any savings on crude cost and increased operating expenses will be worthwhile. **Table 4** lists contaminants that are frequently present in crudes and their specific impacts on refinery operations.

Metals

Metals are commonly found in both heavy and light crude oils in varying amounts. Those that tend to be more abundant are iron, vanadium, nickel, sodium, calcium, magnesium, and aluminum. These are present either as inorganic salts, for instance chlorides of sodium and magnesium, or as organometallic compounds, such as nickel and vanadium porphyrins. During processing, metal chlorides can produce hydrochloric acid, which is corrosive. They also can produce soaps with the carboxylic acids present in some crudes, and this can result in formation of emulsions that degrade desalter performance. On the other hand, organometallic compounds of heavy metals can poison refining catalysts. In the case of FCC processing, effects on the catalyst include zeolite destruction (vanadium, sodium, and potassium), increased coke and dry gas (vanadium, nickel), neutralisation of acid sites (calcium), and blockage of access to interior sites (iron). One means of mitigating these effects is to use catalyst additives that capture and immobilise the metal atoms under regenerator conditions.

Large amounts of contaminant metals can be found in light tight oils due to the nature of the fracking chemicals that are used to produce these crudes. These metals, in particular calcium and iron, have been cited by refiners as problematic in that they may be carried into downstream processing units such as the FCC, resulting in elevated levels of catalyst poisoning and deactivation.

If we turn to heavy crudes, vanadium and nickel are found to be present in much higher levels than are other metals. Concentrations up to 370 ppm and 93 ppm, respectively, have been reported. Vanadium can cause catalyst deactivation in desulphurisation and cracking units and produces a toxic product — vanadium pentoxide — when combusted. This makes it more difficult to upgrade heavy residues economically or to produce saleable coke from crudes with high vanadium levels. While the metal tends to aggregate in the asphaltene fraction of crude, there are not currently any methods to selectively remove it from the asphaltenes. Finally, acidic crudes will often contain calcium and other divalent metals in the form of naphthenates. These originate from production water under conditions of alkaline pH and are soluble in organic media, which means that they can be carried downstream of production. In the refinery, they can precipitate and cause problems such as desalter emulsion stabilisation, desalter water carry-over and oil carry-under, fouling in the CDU preheat exchanger and heater tubes, deactivation of FCC catalyst (see above), and high metals content in heavy fuel oil. Technology is available for dealing with naphthenate contaminants.

Mercury is a contaminant of crude oils at the levels of parts per billion (ppb). Although this is very low, given the volume of crude that is processed annually by the refining industry and the toxicity of mercury and its compounds, the presence of this metal in crudes is of concern. Mercury will concentrate in the heavy refined products such as fuel oil and coke. Another problem for refineries is the tendency of elemental mercury to amalgamate with other metals, especially aluminum, causing embrittlement and cracking. This is a particular concern for LPG cryogenic heat exchangers. The average level of mercury in crude oils varies widely with their regional origin. The range reported is from the low of 0.8 ppb found in Middle Eastern crudes to the high of 220.1 ppb in Asian crudes. Wash water and sorbents are used by refineries to recover mercury wastes.

Chlorides

Two categories of chloride compounds may be found in crude oils being processed in a refinery. One of these is water-extractable chlorides. These compounds can produce highly corrosive hydrochloric acid (HCl) in the overhead of the CDU. However, 90% or more of water-extractable chlorides will be removed from the oil by the desalter unit. Any residual amounts can be dealt with by using neutralising amines, filming corrosion inhibitors, and/or overhead water wash. The other category is non-extractable chlorides, and these fall into two groups: organic molecules with a C-Cl bond, which includes such materials as chlorobenzene, vinyl chloride, and trichloroethylene; and organic amine chlorides. Organic chlorides in crude oils can cause fouling and corrosion in crude towers and corrosion in naphtha hydrotreaters, hydrocracker overheads, and the debutaniser stripper overheads for catalytic reformers.

Nitrogen

The level of nitrogen in most crude oils is less than 0.10 wt%, but it varies overall from less than 0.01 wt% to about 1.00 wt% by elemental analysis. The higher amounts of nitrogen occur in heavy crudes. Nitrogen compounds in petroleum have higher thermal stability than do sulphur species. A consequence of this stability is that during refining these compounds become concentrated in the heavier product fractions and residues. During refining of these materials, NOx can form in furnace flue gases and cause steel corrosion when they are allowed to cool in the presence of water. FCC processing of high-nitrogen feeds from heavy oils and oil sands bitumen can produce corrosion, cracking, and blistering of carbon steel in the overhead system due to formation of ammonia and cyanides. Finally, nitrogen compounds can poison many catalysts. For example, their presence in hydrotreating feeds can inhibit desulphurisation, especially the removal of dibenzothiophenes. Tight oils that are treated with amines to remove H_2S can contain residual amounts of these compounds, which can cause emulsification problems at the desalter.

Sulphur

The sulphur content of crude oils ranges from less than 0.1 wt% to about 5.0 wt% on an elemental basis. This sulphur is present in the form of mercaptans, thiophenes, sulphur oxides, hydrogen sulphide, and elemental sulphur. Major issues regarding sulphur include potential for catalyst deactivation, corrosion of refining equipment, safety concerns (for example, with H_2S), and legislation limiting allowable sulphur levels in fuels. Even with sweeter crude oils, stringent standards on sulphur levels in gasoline and diesel and tightening standards on marine fuel mean that refiners must further treat crudes to remove higher amounts of sulphur. One common method for sulphur removal is hydrotreating — an energy-intensive process requiring around 81K Btu/bbl processed. The extra processing required to remove sulphur from crude also leads to an increased CO_2 footprint for the refiner — a factor that is becoming more and more critical to consider when analysing which crudes to process.

Sulphur content is a particular concern for heavier crudes for two main reasons. First, there is a correlation between higher asphaltene content and higher proportions of sulphur, so these heavy opportunity crudes often contain more sulphur. Secondly, the large amounts of asphaltenes and resins in low API crudes make it more difficult to remove sulphur. High hydrogen partial pressures are needed during hydrotreating, and even hydrocracking conditions may be required to remove sulphur compounds from these heavy fractions. Although light tight oils typically have low overall concentrations of sulphur when compared with heavy crudes, much of that sulphur is in the form of hydrogen sulphide. This can create odour and safety issues during transportation and in the refinery. Excessive amounts of chemicals used to control hydrogen sulphide in the refinery can lead to corrosion problems.

Sulphidic corrosion can occur by direct reaction between metal surfaces and active sulphur compounds like mercaptans, or it can arise when sulphur compounds decompose during refining to form H_2S, which then reacts with metal surfaces. There are interesting interactions between sulphur and naphthenic acids in crude oil. In some cases, sulphur can serve to reduce the severity of naphthenic acid corrosion, while, in other circumstances, the presence of naphthenic acids can act to increase the severity of sulphidic corrosion. For example, in side cuts from the distillation column, a sulphide film may form, which protects the metal surface from naphthenic acids.

Solids

Due to the fracking process that is used to produce them, tight oils can contain small particulates in amounts higher than those found in conventionally produced oils. The loading can be as high as 300 lb (0.14 mt) per thousand bbl of crude. High levels of solids can challenge the ability of the desalter to remove these contaminants, leading to stabilised emulsions that, in turn, cause less than desirable separation of the oil and brine. Oil that is trapped in the brine can result in problems in the wastewater treatment plant. Removal of solids from the desalter is helped by the use of wetting agents.

Conclusion

Blending of price-advantaged crudes offers economic benefits for refiners. In the US, refiners are able to produce lookalike grades of valuable ANS (Alaskan North Slope), LLS (Light Louisiana Sweet), and WTS (West Texas Sour), which are familiar to the West and Gulf Coast refineries. Some known recipes are: Bakken and WCS (West Canadian Select) to make ANS; Mars and Eagle Ford for LLS; and Canada's Cold Lake and North Dakota Light for WTS. However, some blended grades are far from ideal. For instance, when comparing a 50/50 blend of Cold Lake and North Dakota Light to WTS, distillate yield is lower while resid yield is higher, probably due to incompatibility issues. Therefore, crude traders, buyers, and refiners must have a keen knowledge of the important selection and blending criteria and use them as a tool in evaluating, preparing, and processing lookalike crudes as captured in **Figure 1**.

In our follow-up article, in *PTQ*'s Q2 2016

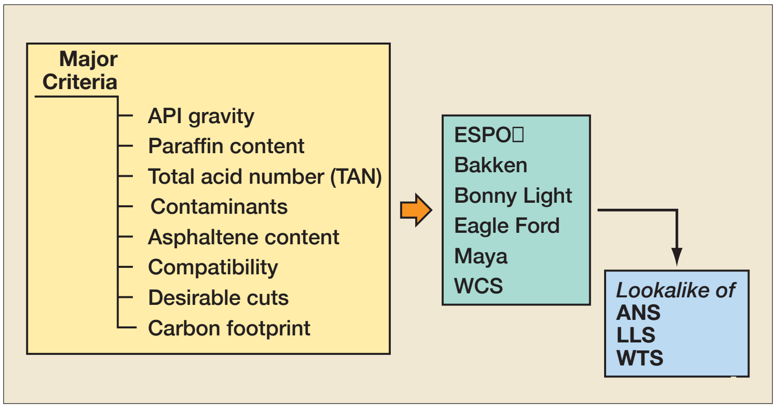

Figure 1 Important criteria to consider for making lookalike crudes

issue, we will take up another set of criteria that are more complex in their characterisation: impacts on desirable feed cuts for a valuable product slate and on carbon footprint, fouling and incompatibility (including the role of asphaltene content). Awareness of these issues is the first step towards finding the solutions, which will be discussed in Hydrocarbon Publishing Company's 5th Opportunity Crudes Conference in Houston, Texas, 10-11 October 2016 (www.opportunitycrudes.com/houston2016/index.php); and upcoming multi-client strategic report, *Advanced Technologies and Novel Strategies to Evaluate, Prepare, and Process Changing Crudes*.

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